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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO ESTABLISH A NEW BASE LEVEL OF NET POWER SUPPLY EXPENSE	)))))	CASE NO. IPC-E-13-20

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TIMOTHY E. TATUM

Q. Please state your name and business address.

A. My name is Timothy E. Tatum and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Senior Manager of Cost of Service in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. I have earned a Bachelor of Business Administration degree in Economics and a Master of Business Administration degree from Boise State University. I have also attended electric utility ratemaking courses, including "Practical Skills for The Changing Electrical Industry," a course offered through New Mexico State University's Center for Public Utilities, "Introduction to Rate Design and Cost of Service Concepts and Techniques" presented by Electric Utilities Consultants, Inc., and Edison Electric Institute's "Electric Rates Advanced Course." In 2012, I attended the "Utility Executive Course" at the University of Idaho.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1996 as a Customer Service Representative in the Company's Customer Service Center where I handled customer phone calls and other customer-related transactions. In 1999, I began working in the Customer Account Management Center where I was responsible for customer account maintenance in the areas of billing and metering.

In June of 2003, after seven years in customer service, I began working as an Economic Analyst on the Energy Efficiency Team. As an Economic Analyst, I was responsible for ensuring that the demand-side management ("DSM") expenses were accounted for properly, preparing and reporting DSM program costs and activities to management and various external stakeholders, conducting cost-benefit analyses of DSM programs, and providing DSM analysis support for the Company's 2004 Integrated Resource Plan.

In August of 2004, I accepted a position as a Regulatory Analyst in the Regulatory Affairs Department. As a Regulatory Analyst, I provided support for the Company's various regulatory activities, including tariff administration, regulatory ratemaking and compliance filings, and the development of various pricing strategies and policies.

In August of 2006, I was promoted to Senior Regulatory Analyst. As a Senior Regulatory Analyst, my responsibilities expanded to include the development of complex financial studies to determine revenue recovery and pricing strategies, including the preparation of the Company's cost-of-service studies.

In September of 2008, I was promoted to Manager of Cost of Service and in April of 2011 I was promoted to Senior Manager of Cost of Service. As Senior Manager of Cost of Service, I oversee the Company's cost-of-service activities such as power supply modeling, jurisdictional separation studies, class cost-of-service studies, and marginal cost studies.

Q. What is the Company requesting in this proceeding?

A. Idaho Power is requesting that the Idaho Public Utilities Commission ("Commission") approve the Company's determination of new normalized or "base level" net power supply expense ("NPSE") to be utilized 1) to update base rates on June 1, 2014, and 2) as the basis for quantifying the 2014/2015 Power Cost Adjustment ("PCA") rates that would also become effective June 1, 2014. If approved, the Company's proposed change in base level NPSE would have no net impact to the overall revenue collected through customer rates and would also be "revenue neutral" for all classes of Idaho customers.

Q. If the overall revenue collected from each customer class would not be affected by this application, why is the Company making this filing?

A. The Company's currently approved normalized level NPSE included in base rates reflects a 2010 normalized condition. Most of the individual cost and revenue components of NPSE have changed significantly and permanently resulting in an overall increase in the normalized level of NPSE of approximately $100 million from the 2010 normalized condition to the 2013 normalized condition. Because these increased expenses are not reflected in base rates, such ongoing and permanent costs are instead currently being recovered through the PCA annually. The Company believes that it is more appropriate for these ongoing and permanent power costs to be recovered through base rates than through PCA rates. Therefore, Idaho Power is proposing to remove the recovery of these additional normalized NPSE from the PCA and instead collect these ongoing NPSE through base rates.

Q. Has the Commission previously expressed concern regarding the recovery of ongoing and permanent power costs in the PCA?

A. Yes. On page 11 of Order No. 32821 regarding the 2013/2014 PCA (Case No. IPC-E-13-10), the Commission expressed concern about the level of ongoing NPSE recovery in the PCA:

> The danger of using the PCA as a cost recovery mechanism for more than the current annual power cost fluctuation is

plainly demonstrated here. The PCA was never intended for long term recovery of costs that continue year to year. It was implemented to properly recover the Company's annual fluctuation in power costs and keep the customers from paying either too little or too much of those costs.

Idaho Power believes its proposal in this case is a simple and effective way to address the Commission's concerns regarding the PCA and would restore the PCA to its intended purpose with no impact to customers' bills.

Q. Please provide an overview of the Company's case.

A. In this case, the Company will provide current computations of normalized NPSE utilizing methods previously supported by the Commission that demonstrate that the level of NPSE recovery in base rates is significantly below the current normalized level of NPSE. By utilizing an artificially low normalized NPSE, an artificially high PCA rate must be approved year after year. Periodic correction of the normalized NPSE in base rates also corrects the PCA price signal.

Mr. Scott Wright is the Company witness in this case who presents the development of proposed base level NPSE as determined using the AURORAxmp model ("AURORA"). Mr. Wright explains the methodology used to determine the normalized NPSE and detail the changes to the modeling inputs that have occurred since the last update.

My testimony in this case will describe the Company's request and the supporting rationale for that request. I will also present the Company's proposed implementation approach that would result in no net change to the annual revenue collected through customer rates. Finally, my testimony will address what the Company believes to be the appropriate regulatory treatment of transmission wheeling revenue.

Q. Please provide a summary of the sections presented in your testimony.

A. My testimony contains five sections. The first section provides the regulatory background that led to the currently approved base level NPSE. In the second section, I present the quantification of the Company's updated base level NPSE based on a 2013 calendar year ("2013 Base Level NPSE") and describe the factors that contributed to changes from the currently approved base level NPSE. The third section describes the Company's proposed approach to implementation that would result in no net change in annual revenue and would have no impact to customer bills. The fourth section of my testimony provides the Company's rationale for making this request. The final section of my testimony describes the Company's view with regard to the appropriate regulatory treatment of transmission wheeling revenue.

Q. Please provide an overview of the intent and design of the PCA mechanism.

A. The PCA is a rate mechanism that quantifies and tracks annual differences between actual NPSE and the normalized or base level of NPSE recovered in the Company's base rates for recovery or credit through an annual rate change each June 1. The PCA mechanism utilizes a 12-month test period of April through March and is composed of a forecast component and a true-up component. The PCA forecast is based on the Company's March Operating Plan and represents the difference between the NPSE forecast from the March Operating Plan and the base level NPSE recovered in the Company's base rates. The PCA true-up includes a backward-looking tracking of differences between the prior year's PCA forecast and actual NPSE incurred by the Company during the prior PCA year. The PCA true-up contains a second component that tracks the collection of the prior year's true-up amount, referred to as the "true-up of the true-up."

I. BACKGROUND

Q. Please provide an overview of the regulatory background that led to the currently approved base level NPSE.

A. In Case No. IPC-E-09-30, Order No. 30978, the Commission approved a Settlement Stipulation that provided for an update of the Company's base level NPSE in 2010. In compliance with Order No. 30978, the Company filed on January 19, 2010, a request to update base level NPSE using a 2010 calendar-year test period (Case No. IPC-E-10-01). On April 13, 2010, the Commission issued Order No. 31042 establishing the Company's base level NPSE at $220,770,137 on a total system basis.

In Case No. IPC-E-11-08, Idaho Power's last general rate case, the Commission issued Order No. 32426 on December 30, 2011, approving a Settlement Stipulation whereby the parties agreed to set base level NPSE at $208,100,936 on a total system basis. This amount held all base level NPSE cost and revenue categories at the same levels established in 2010 by Order No. 31042, with the addition of $23,921,466 in expected revenue from Hoku Materials, Inc. ("Hoku") and $11,252,265 related to demand response program incentive payments. The net effect of adding these two components was a reduction to base level NPSE of $12,669,201.

On March 2, 2012, Idaho Power filed a request to include the Langley Gulch Power Plant in rate base (Case No. IPC-E-12-14). As part of its request, the Company updated base level NPSE pursuant to Order No. 29790 (Case No. IPC-E-05-10) in which the Commission ordered that future filings by the Company that result in the inclusion of plant investment in rate base reflect the associated reduction in power supply costs in base rates. On June 29, 2012, the Commission issued Order No. 32585 establishing the now current base level NPSE of $199,993,778 on a total system basis, a net reduction of $8,107,158 as compared to the previously approved level. This newly established base level NPSE maintained the original 2010 load and fuel cost inputs in the AURORA modeling process with the exception of the addition of Langley Gulch as a generation resource.

II. 2013 BASE LEVEL NPSE

Q. What are the power cost and revenue components that make up base level NPSE?

A. Base level NPSE is comprised of the following Federal Energy Regulatory Commission ("FERC") Accounts: FERC Account 501, Fuel (coal); FERC Account 536, Water for Power; FERC Account 547, Fuel (gas); FERC Account 555, Purchased Power; FERC Account 565, Transmission of Electricity by Others; FERC Account 442, Hoku Revenues (first block energy only); and FERC Account 447, Sales for Resale (typically referred to as surplus sales).

The NPSE component FERC Account 555 includes power purchases under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and non-PURPA purchases. FERC Account 555 also includes incentive payments the Company provides to customers for participating in any of its three demand response programs.

Q. What is the Company's determination of the 2013 Base Level NPSE requested for approval in this proceeding?

A. As quantified by Mr. Wright and presented in his testimony, the 2013 Base Level NPSE is $305.7 million on a total system basis. This represents a change of $105.7 million as compared to the currently approved 2010 base level NPSE amount of $200.0 million.

Q. Please summarize the main factors that contributed to the increase in base level NPSE since the last update.

A. There are three main factors contributing to the increase in base level NPSE since the last update: 1) lower market energy prices, 2) the elimination of anticipated Hoku revenues, and 3) increased energy purchases under PURPA.

Q. How do lower market prices impact the current determination of base level NPSE?

A. Lower market prices impact the current expectation of the normalized level of surplus sales, which serve to offset power supply expenses to the benefit of customers. Lower market prices impact Idaho Power's ability to economically dispatch its thermal generating units for surplus sales. That is, when market energy prices are near or below the dispatch price of the Company's thermal generators, it becomes uneconomical to operate the plants for surplus sales. During times when it is economical to dispatch the thermal units for surplus sales, lower market energy prices reduce the overall value of surplus sales.

Q. What factors have contributed to lower market energy prices since 2010?

A. Lower natural gas prices and increased levels of surplus generation in the Pacific Northwest have contributed to lower market energy prices in recent years.

Q. What is the Company's expectation with regard to revenue collection from Hoku?

A. Electric service to Hoku under its Special Contract terminated on April 26, 2012. Neither Hoku nor its United States bankruptcy trustee has given the Company any indication that it intends to take service in the foreseeable future; therefore, no Hoku first block revenue and subsequently no Hoku load has been included in the determination of the 2013 Base Level NPSE.

Q. What impact has increased energy purchases under PURPA had on base level NPSE?

A. Growth in energy purchases under PURPA has contributed significantly to the increase in NPSE in recent years. As described by Mr. Wright in his testimony, PURPA generation has increased from 119 average megawatts ("aMW") in 2010 to an anticipated 245 aMW in 2013, an increase of 126 aMW or more than double the generation in 2010. PURPA-related energy purchases have increased by approximately $71.0 million since 2010. That represents a 113 percent increase in the PURPA expense over the three-year period.

Q. Were increased loads a factor that contributed to the increase in base level NPSE?

A. No. As described by Mr. Wright in his testimony, annual normalized load for the 2013 update to base level NPSE is projected to be 15.3 million megawatt-hours ("MWh"), the same as the level used in the determination of the currently approved base level NPSE.

Q. Have you prepared a detailed listing of the differences that exist between the currently approved base level NPSE and the proposed 2013 Base Level NPSE?

A. Yes. The following Table 1 presents the differences that exist on a total system basis between the currently approved base level NPSE and the proposed 2013 Base Level NPSE on a detailed component basis:

Table 1. System-Level PCA Accounts:

FERC Account	2010	Proposed 2013	Difference
	Base NPSE	Base NPSE	
Account 501, Coal	$ 167,192,744	$ 108,503,180	$ (58,689,564)
Account 536, Water for Power	1,828,640	2,380,597	551,957
Account 547, Gas	51,934,201	33,367,563	(18,566,638)
Account 555, Non-PURPA	45,510,093	62,606,593	17,096,500
Account 565, Transmission	8,262,000	5,455,955	(2,806,045)
Account 447, Surplus Sales	(124,916,153)	(51,735,153)	73,181,000
Account 442, Hoku Revenues	(23,921,466)	-	23,921,466
Net 95% Accounts	125,890,059	160,578,735	34,688,676
			-
Account 555, PURPA	62,851,454	133,853,869	71,002,415
Account 555, DR Incentives	11,252,265	11,252,265	-
Total	$ 199,993,778	$ 305,684,869	$ 105,691,091

Q. Please describe the information contained in Table 1.

A. Table 1 presents a comparison of the currently approved 2010 base level NPSE and the proposed 2013 Base Level NPSE by detailed FERC Account category on a total system basis. As can be seen on Table 1, FERC Account 501, Coal, representing the Company's normalized coal fuel expense, is lower by approximately $58.7 million. FERC Account 536, Water for Power, representing the water leases expense, has increased by $0.6 million. FERC Account 547, Gas, representing natural gas fuel expense, has decreased by approximately $18.6 million. FERC Account 555, Non-PURPA, representing market energy purchases and power purchase agreements, increased by approximately $17.1 million. FERC Account 565, Transmission, representing third-party transmission expense, decreased by approximately $2.8 million. FERC Account 447, Surplus Sales, representing revenue from the sale of surplus energy, decreased by approximately $73.2 million. FERC Account 442, Hoku Revenues, representing anticipated first block energy revenue from Hoku, decreased from $23.9 million to zero. FERC Account 555, PURPA, representing energy purchases under PURPA, increased by $71.0 million. Finally, FERC Account 555, Demand Response Incentives, representing payments to customers participating in demand response programs, remains unchanged.

Q. In light of the recently filed settlement agreement in Case No. IPC-E-13-14 ("Settlement Agreement") that, if approved, will modify the level of incentive payments made to customers participating in the Company's demand response programs, why is the Company not proposing to update the base level amount of demand response incentive payment recovery as part of this case?

A. The Company believes that the currently approved base level amount of demand response incentive payment recovery of $11.3 million will continue to be an appropriate level of recovery going forward, even in light of the recently filed Settlement Agreement. Absent the modifications to the incentive structure proposed in the Settlement Agreement, the current level of demand response recovery would likely have been below the anticipated level of related incentive expense. However, under the redesigned program incentive structure, the anticipated level of incentive expense will more closely align with the currently approved base level of recovery.

III. IMPLEMENTING A REVENUE NEUTRAL RATE

Q. If approved, how does the Company envision its revenue neutral update to base level NPSE would occur?

A. To successfully implement the proposed revenue neutral update to base level NPSE, the Company is requesting that the Commission issue an order by March 31, 2014, approving Idaho Power's determination of the system-level 2013 Base Level NPSE in the amount of $305,684,869. Receiving an order by March 31, 2014, will allow the Company time to compute the 2014/2015 PCA using the newly established 2013 Base Level NPSE.

On April 15, 2014, Idaho Power will file its annual request to adjust its PCA rates and will request to simultaneously adjust base rates effective June 1, 2014. The Company's PCA request would include a PCA determination based upon a measurement of the forecast April 2014 through March 2015 NPSE to the newly established 2013 Base Level NPSE. Because the 2013 Base Level NPSE will be higher than the current base level NPSE, the resulting proposed PCA collection amount will be lower by the Idaho jurisdictional share of the incremental base level NPSE requested in this case, adjusted for PCA sharing. The Company will also request an equal and offsetting increase to base rates to become effective on June 1, 2014. In other words, base rates would be increased in a manner that will generate the same level of revenue that would have otherwise been allowed for recovery through the PCA.

Q. What is the Idaho jurisdictional share of the $105.7 million difference in system-level base NPSE?

A. Based upon the current energy-based allocation used for PCA computational purposes of 95.53 percent, the Idaho jurisdictional share of the $105.7 million difference in system-level base NPSE would be approximately $101.0 million.

Q. Does the $101.0 million represent the increase to Idaho jurisdictional base rates that the Company plans to request as part of the 2014/2015 PCA filing?

A. No. The Company's proposal in this case envisions a rate adjustment that is intended to maintain the same overall level of revenue recovery from base rates and the PCA in aggregate. In other words, the Company's proposal is intended to be "revenue neutral." To achieve this goal it will be necessary to adjust the $101.0 million difference in Idaho jurisdictional base level NPSE to reflect the 95/5 customer to Company sharing provision that exists in the PCA. With the exception of PURPA expenses and demand response incentive costs, the PCA allows the Company to pass through to customers 95 percent of the annual differences in actual NPSE as compared to the base level NPSE, whether positive or negative.

As can be seen on Table 1, the total system-level difference in NPSE within the FERC accounts that are subject to 95 percent recovery (or credit) under the PCA is approximately $34.7 million. Under the PCA mechanism, the Company would recover 95 percent of the Idaho jurisdictional share of the $34.7 million difference or $31.5 million ($34.7 million x 95.53% x 95.00% = $31.5 million). When the $31.5 million of allowed recovery is combined with 100 percent of the difference in the Idaho jurisdictional share of FERC Account 555, PURPA, of $67.8 million ($71.0 million x 95.53% = $67.8 million), the total allowed recovery under the PCA would be $99.3 million. Therefore, the Company's proposal would result in an increase to base rates of approximately $99.3 million, which includes a $1.7 million reduction to the total difference in Idaho jurisdictional base level NPSE of $101.0 million. This $1.7 million "PCA sharing adjustment" would continue to be reflected in base rates until the Company files its next general rate case or it is otherwise adjusted by Commission Order.

Q. How does the Company propose to allocate the $99.3 million base rate increase to each customer class?

A. The Company proposes to use the same energy allocation basis that would exist under the PCA to apportion the approximately $99.3 million base rate increase to each customer class; that is, in proportion to each class's annual energy consumption. By using the same energy allocation basis applied in next year's PCA filing, each customer class will contribute exactly the same amount of revenue to offset NPSE that would exist under the PCA collection. Exhibit No. 2 demonstrates that the Company's proposal would result in no change to the total amount of revenue by customer class from base rates and the PCA, in aggregate. For illustrative purposes, Exhibit No. 2 has been prepared utilizing the currently approved revenue from base rates and revenue from the 2013/2014 PCA. As can be seen on Exhibit No. 2, the Company's proposal would result in an increase to base rate revenue of $99.3 million and an equal and offsetting reduction in PCA revenue.

Q. Are there other components of the PCA that should be adjusted as part of this case?

A. Yes. The Load Change Adjustment Rate ("LCAR") should be updated effective June 1, 2014, to reflect the incremental change in base level NPSE collected through base rates.

Q. Have you quantified an updated LCAR to become effective June 1, 2014?

A. Yes. By applying the methodology established by Commission Order No. 32206 in Case No. GNR-E-10-03, the LCAR should be increased from the current level of $17.64 per MWh to $24.34 per MWh.

Q. Have you prepared an exhibit that details the derivation of the updated LCAR?

A. Yes. Exhibit No. 3 details the derivation of the updated LCAR amount of $24.34 per MWh. As can be seen on Exhibit No. 3, the numerator of the LCAR has been updated to reflect the new level of NPSE to be collected in base rates.

IV. RATIONALE FOR UPDATING BASE LEVEL NPSE

Q. Why should the Commission approve the Company's proposal to update base level NPSE at this time?

A. As demonstrated by the Company's determination of the 2013 Base Level NPSE, the PCA collects approximately $99.3 million annually from Idaho customers for ongoing and permanent NPSE. The Company believes that it is more appropriate for these ongoing and permanent power costs to be recovered through base rates than through PCA rates. The collection of significant ongoing and permanent costs through the PCA has compromised the intended symmetrical design of the PCA and has created counterintuitive messaging on customers' bills.

Q. How has the collection of significant ongoing and permanent costs through the PCA compromised the intended symmetrical design of the PCA and created counterintuitive messaging on customers' bills?

A. As mentioned earlier in my testimony, the PCA is a rate mechanism that quantifies and tracks annual differences between actual NPSE and the normalized level of NPSE recovered in the Company's base rates. These differences may exist as a result of changes in hydro conditions, fuel costs and/or market energy prices. While fuel costs and market energy prices contribute to annual fluctuations in NPSE, it is the availability of hydroelectric generation that can have the most significant impact on year-to-year differences in NPSE. When the Company's base level NPSE is reflective of current normalized NPSE, one would expect that a better than average water-year would result in a negative PCA or a credit, and a worse than average water-year would result in a positive PCA or a surcharge. Because the PCA is collecting nearly $100 million in ongoing and permanent NPSE, the annual PCA collection is likely to always be positive or a surcharge to customers, even in a good water-year. This is not representative of the symmetrical mechanism the PCA was intended to be and has been a source of confusion for customers.

Q. Has the Commission ever approved an adjustment to the level of normalized NPSE recovered in base rates outside of a general rate case?

A. Yes. The currently approved base level NPSE was originally established in 2010 outside of a general rate case in Case No. IPC-E-10-01. In that 2010 case, the Company filed a request very similar to its request in this case. The Commission ultimately issued Order No. 31042 establishing a new base level of NPSE to be used in the Company's 2010/2011 PCA filing. On April 15, 2010, the Company filed Case No. IPC-E-10-12 requesting that the Commission approve its 2010/2011 PCA rate determination based on the base level NPSE approved by Order No. 31042 to become effective June 1, 2010. In that same case, the Company also requested an adjustment to base rates to reflect the newly established base level NPSE, also to become effective June 1, 2010. The Company's request was approved by Order No. 31093 on May 28, 2010.

V. TRANSMISSION WHEELING REVENUE

Q. Please provide an overview of issues related to transmission wheeling revenues that were raised in the Company's 2013/2014 PCA, Case No. IPC-E-13-10.

A. In the 2013/2014 PCA filing, Case No. IPC-E-13-10, the Commission invited the parties to comment on whether the Company's PCA calculation should only include transmission expenses, as has been the practice since 2009, or should be expanded to include both transmission expenses and revenues. Commission Staff and intervenors explained that they believed there was a mismatch by only including third-party transmission expense and not transmission wheeling revenue. The Company subsequently filed reply comments arguing to the contrary; however, the Commission ultimately concluded that excluding transmission wheeling revenue differences from the PCA results in a regulatory mismatch. In support of its conclusion, the Commission made the following findings:

> We reject the Company's claim that a mismatch will arise if the Company's PCA includes transmission wheeling revenues without their associated costs. The Company provided no detail about these costs. We expect they are *de minimis*.
>
> Order No. 32821, page 13.

Q. What was the Commission's directive to the Company regarding transmission wheeling revenue in Order No. 32821?

A. Order No. 32821 issued in the 2013/2014 PCA docket (Case No. IPC-E-13-10), directed the Company to establish a base level of transmission wheeling revenue in the next rate case so that deviations may be tracked through the PCA. Order No. 32821, page 13.

Q. Does the Company believe that this case provides the venue in which the Commission intended Idaho Power to comply with its directive regarding transmission wheeling revenue?

A. No. Because the Company's proposal in this case is intended to be revenue neutral, it would not be appropriate to establish a base level amount for a new PCA component as part of this case. The Company believes that it was the Commission's intent that a new base level of transmission wheeling revenue would be established as part of a broader general rate case where the associated transmission costs would also be addressed.

Notwithstanding this view, the Company believes that it is appropriate as part of this case to provide the Commission with additional detailed information that demonstrates the significant regulatory mismatch that would occur as a result of *including* transmission wheeling revenues as an offset to third-party transmission expense in the PCA.

Q. What is transmission wheeling?

A. Transmission wheeling refers to the transfer of electric power by use of the transmission network of one utility for the benefit of a transmission customer, such as another utility or an independent power generator. Transmission wheeling is commonly referred to as transmission service and is provided under a FERC-approved Open Access Transmission Tariff ("OATT"). The OATT sets out the terms and conditions of service and rates to customers for transmission services.

Q. What are third-party transmission expenses?

A. Third-party transmission expenses result when Idaho Power purchases transmission service from other transmission owners 1) to move purchased power over their system(s) into Idaho Power's system for service to customers or 2) to move surplus sales off of the Idaho Power system on to the transmission system(s) of other transmission owners. These expenses result from PCA-related transactions and are booked to FERC Account 565. Such expenses have been included in the PCA since 2009 (Case No. IPC-E-09-11).

Q. What are transmission wheeling revenues?

A. Transmission wheeling revenues result when third-parties buy capacity on Idaho Power's transmission system to facilitate the movement of their power. These third-party transmission customers are charged the OATT rate and the revenues Idaho Power receives are booked to FERC Account 456 and serve to offset the Company's transmission-related costs or revenue requirement.

Q. What costs are being recovered through Idaho Power's OATT formula rate?

A. The transmission formula rate outlined in Attachment H of the OATT is designed to recover the cost of owning, operating, and maintaining Idaho Power's transmission facilities. The rate specifically excludes expense accounts or plant items the FERC has deemed to be generation related and not appropriately recovered in the transmission formula rate, even though those items are properly recorded in the transmission function FERC accounts.

Q. Have you prepared any exhibits that detail the FERC Accounts used in Idaho Power's transmission formula rate?

A. Yes. Exhibit No. 4 is Attachment H "Total Transmission Revenue Requirement" from Idaho Power's FERC-approved OATT and Exhibit No. 5 details the current rate calculation which sets forth the method used to calculate the total amount of transmission costs to be recovered.

Q. Please summarize the major cost components of the transmission formula rate as presented in Exhibit No. 4.

A. The major cost components of the transmission formula rate, as described fully in Exhibit No. 4 section 3.0 are as follows:

1) Transmission Rate Base (Transmission Plant recorded in FERC Accounts 350 to 359) plus transmission-related general and intangible plant, transmission related working capital, less the associated accumulated depreciation,

2) Return and associated income taxes on rate base,

3) Direct transmission expenses including depreciation, operations and maintenance (FERC Accounts 560 to 573 excluding FERC Accounts 561 and 565) and an allocated portion of general and administrative and general expenses, and

4) Prior year short-term and non-firm transmission revenue credits.

Q. Are third-party transmission expenses incurred by the Company included in the cost components of the transmission formula rate?

A. No. As depicted in Exhibit No. 4, the OATT rate specifically excludes third-party transmission expenses because they are not expenses related to Idaho Power's transmission system.

Q. What is the magnitude of the transmission-related costs currently authorized for recovery through the transmission rate in the Company's OATT?

A. As can be seen on line 45 of Exhibit No. 5, the transmission-related costs currently authorized for recovery through the transmission formula rate in the Company's OATT are approximately $118.2 million.

Q. Is any portion of the transmission-related costs that transmission wheeling revenues are intended to offset tracked through the PCA?

A. No. There is no portion of Company-owned transmission-related costs of which transmission wheeling revenues are intended to recover that are tracked through the PCA.

Q. To what extent do transmission wheeling revenues from third-parties offset the Company's transmission-related costs?

A. In 2012, the Company received approximately $21.1 million in transmission wheeling revenues from third-parties. Revenue from the Company's base rates is intended to offset the remaining transmission-related costs.

Q. Does the Company view its current level of transmission-related costs offset by transmission wheeling revenue from third-parties to be *de minimis*?

A. No. Transmission wheeling revenue from third-parties offsets approximately $21.1 million of the Company's total transmission-related costs of $118.2 million, or nearly 18 percent.

Q. How are transmission wheeling revenues treated in Idaho Power's base rates?

A. Retail customers receive the benefit of transmission wheeling revenues as a revenue credit in base rates. The test-year level of transmission wheeling revenues is set at the time of a general rate case to offset the test-year amount of transmission investment and expenses in the Company's revenue requirement determination. The test year level of transmission wheeling revenues in base rates is reflective of the transmission plant and expense information current at the time of the test year.

Q. Does the Company believe that a general rate case is the appropriate proceeding to set the level of transmission wheeling revenues reflected in customer rates?

A. Yes. Base level transmission wheeling revenues and base level transmission expenses should be based on the same test period. Introducing transmission wheeling revenues as an offset to base transmission expenses outside a general rate case creates an improper matching of transmission wheeling revenues and transmission expenses.

Q. What is the Company's recommendation with regard to the future regulatory treatment of transmission wheeling revenues?

A. The Company believes it has provided evidence to show that transmission wheeling revenues do not offset third-party transmission expenses and should not be tracked through the PCA. However, if the Commission is not swayed by this evidence, then the Company recommends that transmission wheeling revenues remain out of the PCA until the Company files its next general rate case, a time when the Commission can approve an appropriate regulatory treatment.

VI. CONCLUSION

Q. Please summarize the Company's request in this proceeding.

A. Idaho Power requests that the Commission approve the Company's determination of new normalized or base level NPSE to be utilized 1) to update base rates on June 1, 2014 and 2) as the basis for quantifying the 2014/2015 PCA rates that would also become effective June 1, 2014. If approved, the Company's proposed change in base level NPSE would have no net impact to the overall revenue collected through customer rates and would also be "revenue neutral" for all classes of Idaho customers.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
) ss.
County of Ada   )

I, Timothy E Tatum, having been duly sworn to testify truthfully, and based upon my personal knowledge, state the following:

I am employed by Idaho Power Company as a Senior Manager in the Regulatory Affairs Department and am competent to be a witness in this proceeding.

I declare under penalty of perjury of the laws of the state of Idaho that the foregoing pre-filed testimony and exhibits are true and correct to the best of my information and belief.

DATED this 1st day of November, 2013.

Timothy E. Tatum
Timothy E. Tatum

SUBSCRIBED AND SWORN to before me this 1st day of November, 2013.

Kimberly K. Towell
Notary Public for Idaho
Residing at: Star, Idaho
My commission expires: 12-20-2014

KIMBERLY K. TOWELL
NOTARY
PUBLIC
STATE OF IDAHO

KIMBERLY K. TOWELL
NOTARY PUBLIC
STATE OF IDAHO

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-20

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 2

Idaho Power Company
Summary of Revenue Impact
State of Idaho
New Base Level Net Power Supply Expenses

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	Current Revenue Base	Current Revenue PCA	Current Revenue Total	Adjusted Revenue (Example) Base	Adjusted Revenue (Example) PCA	Adjusted Revenue (Example) Total	Percent Change
	Uniform Tariff Rates:										
1	Residential Service	1	404,797	4,813,284,883	$402,404,278	$59,232,089	$461,636,367	$437,919,601	$23,716,766	$461,636,367	0.00%
2	Master Metered Mobile Home Park	3	23	4,891,664	$387,724	$60,197	$447,920	$423,817	$24,103	$447,920	0.00%
3	Residential Service Energy Watch	4	0	0	$0	$0	$0	$0	$0	$0	N/A
4	Residential Service Time-of-Day	5	1,577	25,732,707	$2,061,117	$316,666	$2,377,782	$2,250,988	$126,794	$2,377,782	0.00%
5	Small General Service	7	28,092	143,366,943	$15,315,671	$1,764,268	$17,079,938	$16,373,518	$706,420	$17,079,938	0.00%
6	Large General Service	9	32,374	3,583,313,096	$213,315,181	$44,096,106	$257,411,287	$239,755,030	$17,656,257	$257,411,287	0.00%
7	Dusk to Dawn Lighting	15	0	6,429,995	$1,235,893	$79,127	$1,315,020	$1,283,337	$31,683	$1,315,020	0.00%
8	Large Power Service	19	109	2,114,297,079	$95,672,971	$26,018,454	$121,691,425	$111,273,532	$10,417,893	$121,691,425	0.00%
9	Agricultural Irrigation Service	24	16,911	1,708,623,743	$114,163,808	$21,026,255	$135,190,063	$126,771,066	$8,418,997	$135,190,063	0.00%
10	Unmetered General Service	40	1,288	12,164,524	$901,887	$149,696	$1,051,583	$991,644	$59,939	$1,051,583	0.00%
11	Street Lighting	41	1,251	26,654,710	$3,183,720	$328,012	$3,511,732	$3,380,395	$131,337	$3,511,732	0.00%
12	Traffic Control Lighting	42	431	2,810,533	$141,398	$34,586	$175,984	$162,136	$13,848	$175,984	0.00%
13	Total Uniform Tariffs		486,853	12,441,569,877	$848,783,647	$153,105,455	$1,001,889,102	$940,585,064	$61,304,037	$1,001,889,102	0.00%
14	Special Contracts:										
15	Micron	26	1	587,867,669	$22,410,369	$7,234,276	$29,644,644	$26,748,012	$2,896,633	$29,644,644	0.00%
16	J R Simplot	29	1	192,687,586	$6,845,067	$2,371,206	$9,216,272	$8,266,832	$949,440	$9,216,272	0.00%
17	DOE	30	1	236,974,493	$8,845,806	$2,916,199	$11,762,004	$10,594,347	$1,167,658	$11,762,004	0.00%
18	Hoku - Retail	32	0	0	$0	$0	$0	$0	$0	$0	N/A
19	Total Special Contracts		3	1,017,529,748	$38,101,241	$12,521,680	$50,622,921	$45,609,190	$5,013,731	$50,622,921	0.00%
20	**Total Idaho Retail Sales**		**486,856**	**13,459,099,625**	**$886,884,888**	**$165,627,135**	**$1,052,512,023**	**$986,194,255**	**$66,317,768**	**$1,052,512,023**	**0.00%**
21	Hoku - Block 1 Energy	32		0	$0	0.00		$0	$0	0.00	N/A

(1) 2013 PCA Test Year

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-20

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 3

IDAHO POWER COMPANY
Development of Load Change Adjustment Rate
New Base Level Net Power Supply Expenses

	A	B	C	D	E
	Energy-Related Generation Function Revenue Requirement	Requested Increase to Base Net Power Supply Expenses	Adjusted Energy-Related Generation Function Revenue Requirement	2011 Test Year Idaho Jurisdictional Load at Generation Level (MWh)	Load Change Adjustment Rate ($/MWh)
Source	Case No. IPC-E-12-14	DI Tatum, p. 17, l. 18	A + B	Case No. IPC-E-11-08	C ÷ D
Generation Function Energy-Related	$261,437,727	$99,309,367	$360,747,094	14,822,063	$24.34

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-20

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 4

ATTACHMENT H

Total Transmission Revenue Requirement

1.0 Methodology

This formula sets forth the method that the Transmission Provider will use to determine its annual Total Transmission Revenue Requirement. The Total Transmission Revenue Requirement reflects the Transmission Provider's total cost to own, operate and maintain the transmission facilities used for providing Open Access Transmission Service to transmission customers under this Tariff.

The Total Transmission Revenue Requirement will be an annual formula rate calculation, and will be based on the previous calendar year's FERC Form 1 data and the Transmission Provider's books and records where greater detail is required. The Total Transmission Revenue Requirement shall be effective for an initial term commencing June 1, 2006 and ending on September 30, 2007. Thereafter, the Total Transmission Revenue Requirement shall be effective October 1, of each year, and ending September 30 of the following year.

1.1 Annual Informational Filing

1.1.1 On or before June 1 of each year or as soon as practical thereafter[1], the Transmission Provider shall post a draft Informational Filing on the publicly accessible portion of its OASIS (the "Posting Date"). The posting will notify Transmission Customers of the date of the meeting to be held pursuant to Section 1.1.3. If the posting is made prior to June, the Transmission Provider shall provide notice via e-mail to the parties in Docket No. ER06-787.

1.1.2 The draft Informational Filing shall include the following information:

(a) The rates and revenue requirements for transmission service under Schedules 7, 8 and 9 of this Tariff;

(b) The formula rate calculation and all inputs thereto, in Microsoft Excel spreadsheet format (inclusive of all formulas, references and linkages), in a form similar to that which the Transmission Provider provided to Transmission Customers and posted on its OASIS on May 22, 2006;

(c) Allocation demand and capability data, in a form similar to that included in the Statement BB workpapers filed on March 24, 2006 in Docket No. ER06-787-000, and a reconciliation of such data with the FERC Form 1 load data;

[1] These procedures shall become effective August 1, 2007, and all other dates set out in Section 1.1 shall be adjusted accordingly for 2007 only.

(d) The generator step-up substation (including jointly-owned generator step-up substations) plant investment, depreciation reserve, depreciation expense, and operation and maintenance expense;

(e) The property taxes directly assigned to transmission and general plant, as reflected in Section 3.7;

(f) Workpapers showing Account 454 revenues, which shall identify the types of revenue sources and the amount of each source, describe the nature of each such source, and indicate the allocation treatment;

(g) Workpapers showing the Account 456 revenue included as revenue credits, which shall contain annual data by customer, and which shall identify the transmission-related revenues reported in Account 456 that are included as revenue credits and those for which the transactions are included in the rate divisor;

(h) Workpapers showing the calculation of the Long-Term Debt Component included in Section 3.1.2.1;

(i) Workpapers showing the calculation of the Equity AFUDC component of Transmission Depreciation and Amortization Expense included in Section 3.1.2.2;

(j) Workpapers showing the calculation of the State Income Tax Rate used in Section 3.1.2.2(b);

(k) The plant investment, depreciation reserve, depreciation expense and operation and maintenance expense associated with the Transmission Provider directly-assigned Interconnection Facilities excluded from transmission rate base pursuant to Section 2.2.10 of the formula rate;

(l) The data used in the formula rate for Network Upgrade Prepayments and Reimbursable Interest;

(m) A list of substantive changes to the Transmission Provider's accounting policies, practices and procedures from those in effect for the calendar year upon which the immediately preceding Informational Filing was based that could affect the charges under the formula rate;

(n) A description of each item of new transmission plant installed during the calendar year upon which the Informational Filing is based with a cost in excess of $250,000; and

(o) For costs based on 2005 and 2006 data only, workpapers showing the calculation of the revenue credit for Non-Firm Point-to-Point Transmission Service and Short-Term Firm Point-to-Point Transmission Service under the Tariff.

The above list does not preclude the Transmission Provider from including in the draft Informational Filing additional information to that set forth above.

1.1.3 The Transmission Provider will hold an open meeting within 14 to 21 days from the Posting Date to explain and clarify the draft Informational Filing. A Transmission Customer and any parties in Docket No. ER06-787 may make reasonable requests to the Transmission Provider for additional information relating to the formula rate inputs from the Posting Date until 60 days thereafter. Such information requests will be limited to what is necessary to determine if the Transmission Provider has properly applied the formula rate, and will not be directed to determining whether the formula rate is just and reasonable. The Transmission Provider will respond to such requests in a reasonable time frame, typically 10 to 15 business days, unless the Transmission Provider disagrees as to the reasonableness of such requests, in which case the matter will be subject to the Dispute Resolution Procedures set forth in Section 12 of the Tariff (except that the requirements of Section 12.2 regarding senior representative review will be eliminated and all time periods in Section 12.3 and 12.4 will be shortened by half). The Transmission Provider will not be required to respond to any such contested request pending the outcome of such procedures. The Transmission Customer and any parties in Docket No. ER06-787 will submit any comments on the draft Informational Filing to the Transmission Provider no later than 75 days following the Posting Date.

1.1.4 Within 90 days following the Posting Date, the Transmission Provider shall post the Informational Filing on the publicly accessible portion of its OASIS and submit such filing to FERC. The Informational Filing will include the information described in Section 1.1.2 and any modifications thereto that the Transmission Provider made. The Transmission Provider will advise the parties that submitted comments on the draft Informational Filing of the comments that the Transmission Provider agrees with and provide a reference to applicable resulting change(s). The Transmission Provider will not propose any modifications to the formula rate or the Tariff in the Informational Filing. The Informational Filing does not re-open the formula rate for review or challenge, and shall not constitute a rate change filing under Section 205 of the Federal Power Act. If there are any corrections to the Informational Filing after it is submitted to FERC, the Transmission Provider shall post such corrections on the publicly accessible portion of its OASIS and file the corrections with FERC.

1.1.5 A Transmission Customer and any parties in Docket No. ER06-787 may challenge the Informational Filing by filing a protest at FERC.

1.1.6 If the Transmission Provider files a revision to its FERC Form 1 that affects the formula rate calculations, the Transmission Provider will post such revisions on the publicly accessible portion of its OASIS. In addition, if the Transmission Provider files revisions to its FERC Form 1 after it posts its draft Informational Filing on the OASIS, the Transmission Provider will post on the publicly accessible portion of its OASIS a list of such revisions and the associated changes the revision has on the Informational Filing.

2.0 Definitions

Capitalized terms not otherwise defined in Section I of this Tariff have the following definitions:

2.1 Allocation Factors

2.1.1 Transmission Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Provider's Transmission-related Direct Wages and Salaries to the Transmission Provider's total direct wages and salaries excluding administrative and general wages and salaries.

2.1.2 Plant Allocation Factor shall equal the ratio of the sum of total investment in Transmission Plant, Transmission Related General Plant and Transmission Related Intangible Plant to Total Plant in Service.

2.2 Terms

2.2.1 Administrative and General Expense shall equal the Transmission Provider's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1, and EPRI dues recorded in Account No. 930.2; provided, that for rates in effect after September 30, 2007, the Transmission Provider will make a Section 205 filing to implement any increase in the expense for post-retirement benefits other than pensions that results in an increase in the rate for Firm Point-to-Point Transmission Service of more than $.05/kW-month, as compared to the rate for Firm Point-to-Point Transmission Service in effect for the immediately preceding Service Year.

2.2.2 Amortization of Intangible Plant Expense shall equal the Transmission Provider's balance in Account 404 – Amortization of Limited Term Electric Plant.

2.2.3 Amortization of Investment Tax Credits shall equal the Transmission Provider's credits as recorded in FERC Account No. 411.4.

2.2.4 Amortization of Other Utility Plant shall equal the Transmission Provider's Amortization of Other Utility Plant balance in Account 111.

2.2.5 Depreciation Expense for Transmission Plant shall equal the Transmission Provider's transmission expense as recorded in FERC Account No. 403 (excluding the portion of such depreciation expense associated with the Transmission Provider's (1) solely- and jointly-owned generator step-up facilities and (2) IPC Order 2003 Interconnection Facilities); provided, that if the depreciation rates used to calculate transmission expense as recorded in FERC Account No. 403 differ from those set forth in Section 4.1, then, solely for purposes of calculating Depreciation Expense for Transmission Plant for use in this formula rate, the calculation of transmission expense as recorded in FERC Account No. 403 shall be modified as necessary to reflect the depreciation rates set forth in Section 4.1.

2.2.6 General Plant shall equal the Transmission Provider's gross plant balance as recorded in FERC Account Nos. 389-399.

2.2.7 General Plant Depreciation Expense shall equal the Transmission Provider's general plant depreciation expenses as recorded in FERC Account No. 403; provided, that if the depreciation rates used to calculate general plant expense as recorded in FERC Account No. 403 differ from those set forth in Section 4.1, then, solely for purposes of calculating Depreciation Expense for General Plant for use in this formula rate, the calculation of general plant expense as recorded in FERC Account No. 403 shall be modified as necessary to reflect the depreciation rates set forth in Section 4.1.

2.2.8 General Plant Depreciation Reserve shall equal the Transmission Provider's general plant reserve balance as recorded in FERC Account No. 108 (excluding the portion of such reserve balance associated with the Transmission Provider's asset retirement costs for general plant), except as provided in Section 4.2.

2.2.9 Idaho Power Order 2003 Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities, as that term is defined in Attachment M of the Tariff, that were constructed on or after March 15, 2000, and that are associated with the Transmission Provider's generating units, provided that such facilities do not comprise part of the Transmission Provider's Transmission System, as that term is defined in Attachment M of the Tariff.

2.2.10 Intangible Plant shall equal the Transmission Provider's plant balance as recorded in FERC Account Nos. 301-303

2.2.11 Network Upgrade Prepayments and Reimbursable Interest shall equal the reimbursable prepayments made by an Interconnection Customer for a Network Upgrade constructed under a Large Generator Interconnection Agreement and associated reimbursable interest earned by the Interconnection Customer during construction of the Network Upgrade, recorded in Account 252.

2.2.12 Other Fees and Charges shall equal the Transmission Provider's balance in FERC Account Nos. 408.1 and 409.1 excluding Payroll Taxes, Property Taxes the license tax on the production of electricity through the use of water power assessed under Idaho Code § 63-2701, franchise fees assessed by municipalities in Oregon, fees assessed by the Idaho Public Utilities Commission under Idaho Code §§ 61-1001 through 61-1008 for the costs of such Commission, and fees assessed by the Public Utility Commission of Oregon under Oregon Revised Statute § 756.310 for the costs of such Commission.

2.2.13 Other Regulatory Assets/Liabilities – FAS 106 shall equal the net of the Transmission Provider's FAS 106 balance as recorded in FERC Account No. 182.3 and the FAS 106 balance as recorded in the Transmission Provider's FERC Account No. 254.

2.2.14 Other Regulatory Assets/Liabilities – FAS 109 shall equal the net of the Transmission Provider's FAS 109 balance in FERC Account No. 182.3 and the FAS 109 balance as recorded in the Transmission Provider's FERC Account No. 254 as adjusted for offsetting amounts related to FAS 109 in accounts identified as accumulated deferred income taxes.

2.2.15 Payroll Taxes shall equal those payroll expenses as recorded in the Transmission Provider's FERC Account Nos. 408.1 and 409.1, less the payroll loading reversal.

2.2.16 Plant Held for Future Use shall equal the Transmission Provider's balance in FERC Account No. 105.

2.2.17 Prepayments shall equal the Transmission Provider's prepayment balance as recorded in FERC Account No. 165, excluding prepaid pension expense.

2.2.18 Property Insurance shall equal the Transmission Provider's expenses as recorded in FERC Account No. 924.

2.2.19 Property Taxes shall equal the Transmission Provider's property tax balance in FERC Accounts 408.1 and 409.1.

2.2.20 Total Accumulated Deferred Income Taxes shall equal the net of the Transmission Provider's deferred tax balance as recorded in FERC Account Nos. 281-283 and the Transmission Provider's deferred tax balance as recorded in FERC Account No. 190, as adjusted for offsetting amounts related to FAS 109 in accounts identified as regulatory assets or liabilities.

2.2.21 Total Materials and Supplies shall equal the Transmission Provider's balance in FERC Account Nos. 154 and 163.

2.2.22 Total Plant In Service shall equal the Transmission Provider's total gross plant balance as recorded in FERC Account Nos. 301-399, excluding asset retirement costs recorded in FERC Account Nos. 317, 326, 337, 347, 359.1 and 374.

2.2.23 Total Transmission Depreciation Reserve shall equal the Transmission Provider's Transmission reserve balance as recorded in FERC Account No. 108, excluding the portion of such reserve balance associated with the Transmission Provider's (1) solely- and jointly-owned generator step-up facilities (2) IPC Order 2003 Interconnection Facilities and (3) asset retirement costs for transmission plant, except as provided in Section 4.2.

2.2.24 Transmission Operation and Maintenance Expense shall equal:

- the Transmission Provider's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573, less RTO development costs amortized to these accounts, less
- the portion of such expense associated with the Transmission Provider's solely- and jointly-owned generator step-up facilities (for which the Transmission Provider shall have a separate work order or its functional equivalent), less
- the product of (1) the Transmission Provider's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 and (2) the ratio of (a) IPC Order 2003 Interconnection Facilities and (b) Transmission Plant plus (i) the portion of the Transmission Provider's gross plant balance associated with the Transmission Provider's solely- and jointly-owned generator step-up facilities and (ii) IPC Order 2003 Interconnection Facilities..

2.2.25 Transmission Plant shall equal the Transmission Provider's gross plant balance as recorded in FERC Account Nos. 350-359, excluding the portion of such gross plant balance associated with the Transmission Provider's (1) solely- and jointly-owned generator step-up facilities and (2) IPC Order 2003 Interconnection Facilities.

2.2.26 Transmission-related Direct Wages and Salaries shall equal Transmission-related direct wages and salaries multiplied by the ratio of (a) Transmission Plant to (b) the sum of Transmission Plant and the gross plant balance associated with the Transmission Provider's (1) solely- and jointly-owned generator step-up facilities and (2) IPC Order 2003 Interconnection Facilities.

3.0 Total Transmission Revenue Requirement Calculation

The Total Transmission Revenue Requirement shall equal the sum of the Transmission Provider's:

- Return and Associated Income Taxes,
- Transmission Depreciation Expense,
- Transmission Related Amortization of Investment Tax Credits,
- Transmission Operation and Maintenance Expense,
- Reimbursable interest earned by an Interconnection Customer following the Commercial Operation Date of the Interconnection Customer's Generating Facility that the Transmission Provider reimburses to the Interconnection Customer,
- Transmission Related Administrative and General Expense,
- Transmission Related Taxes Other than Income Taxes, and
- Amortization of RTO Development Costs.

3.1 <u>Return and Associated Income Taxes</u> shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

3.1.1 <u>Transmission Investment Base</u> will be the end of year balances of:

- Transmission Plant, less
- The unreimbursed portion of Network Upgrade Prepayments and Reimbursable Interest, net of the accumulated depreciation reserve associated with the Network Upgrades to which the Network Upgrade Prepayments and Reimbursable Interest relate, plus
- Transmission Related General Plant, plus
- Transmission Related Intangible Plant, plus
- Transmission Related Plant Held for Future Use, less
- Transmission Related Depreciation and Amortization Reserve, less
- Transmission Related Accumulated Deferred Taxes, plus
- Other Regulatory Assets/Liabilities, plus
- Transmission Prepayments, plus
- Transmission Related Materials and Supplies, plus

- Transmission Related Cash Working Capital, plus
- Unamortized RTO Development Costs.

3.1.1.1 Transmission Plant will equal the balance of the Transmission Provider's investment in Transmission Plant, as defined in Section 2.2.25.

3.1.1.2 Transmission Related General Plant shall equal the Transmission Provider's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

3.1.1.3 Transmission Related Intangible Plant shall equal the Transmission Provider's balance of investment in Intangible Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

3.1.1.4 Transmission Related Plant Held for Future Use shall equal the Transmission Provider's balance of Transmission Plant Held for Future Use, plus general Plant Held for Future Use multiplied by the Transmission Wages and Salaries Allocation Factor.

3.1.1.5 Transmission Related Depreciation and Amortization Reserve shall equal the balance of the Transmission Provider's:

- Total Transmission Depreciation Reserve, plus
- Transmission Related General Plant Depreciation Reserve and the Transmission Related Amortization of Other Utility Plant

(i) Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(ii) Transmission Related Amortization of Other Utility Plant shall equal the product of Amortization of Other Utility Plant and the Transmission Wages and Salaries Allocation Factor.

3.1.1.6 Transmission Related Accumulated Deferred Taxes shall equal the Transmission Provider's electric balance of Total Accumulated Deferred Income Taxes multiplied by the Plant Allocation Factor.

3.1.1.7 Transmission Related Other Regulatory Assets/Liabilities shall equal the Transmission Provider's Other Regulatory Assets/Liabilities-FAS 106 multiplied by the Transmission Wages and Salaries Allocation Factor, plus the Transmission Provider's Other

Regulatory Assets/Liabilities-FAS 109 multiplied by the Plant Allocation Factor.

3.1.1.8 Transmission Prepayments shall equal Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

3.1.1.9 Transmission Related Materials and Supplies shall equal the Transmission Provider's balance assigned to transmission as recorded in FERC Account 154; plus the Transmission Related portion of Account 154 assigned to General Plant, determined as the product of the balance assigned to General Plant and the Transmission Wages and Salaries Allocation Factor; plus the Transmission Related portion of Account 163, determined as the balance in Account 163 multiplied by the Plant Allocation Factor.

3.1.1.10 Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Provider's Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

3.1.1.11 Unamortized RTO Development Costs shall be:

(a) $4,229,802 for the period May 1, 2008 – September 30, 2008

(b) $3,306,936 for the period October 1, 2008 – September 30, 2009

(c) $2,384,070 for the period October 1, 2009 – September 30, 2010

(d) $1,461,204 for the period October 1, 2010 – September 30, 2011

(e) $538,338 for the period October 1, 2011 – September 30, 2012

(f) Commencing October 1, 2012, Unamortized RTO Development Costs shall be $0.

3.1.2 Cost of Capital Rate will equal the Transmission Provider's:

- Weighted Cost of Capital, plus
- Federal Income Tax, plus
- State Income Tax.

3.1.2.1 Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of the Long-term Debt Component, The Preferred Stock Component, and the Return on Equity Component.

(i) The Long-term Debt Component shall equal the product of the actual weighted average embedded cost to maturity of the Transmission Provider's long-term debt then outstanding and the ratio that long-term debt is to the Transmission Provider's total capital.

(ii) The Preferred Stock Component shall equal the product of the actual weighted average embedded cost to maturity of the Transmission Provider's preferred stock then outstanding and the ratio that preferred stock is to the Transmission Provider's total capital.

(iii) The Return on Equity Component shall equal the product of the Transmission Provider's Return on Equity ("ROE") of 10.7% and the ratio that common equity is to the Transmission Provider's total capital. This ROE will remain effective until new ROE provisions are made effective for the Transmission Provider.

3.1.2.2 Federal Income Tax shall equal

[(A + [(C+B) / D]) x (FT)] divided by (1-FT)

where;

FT is the Federal Income Tax Rate

A is the sum of the preferred stock component and the return on equity component, as determined in Sections 3.1.2.1(ii) and (iii) above.

B is the Transmission Related Amortization of Investment Tax Credits, as determined in Section 3.4 below.

C is the Equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section 3.2 and

D is the Transmission Investment Base, as determined in Section 3.1.1, above.

3.1.2.3 State Income Tax shall equal

(A + [(C+B) / D] + Federal Income Tax) x (ST) divided by (1-ST)

where;

ST is the State Income Tax Rate,

A is the sum of the preferred stock component and return on equity component determined in Sections 3.1.2.1 (ii) and (iii) above,

B is the Amortization of Investment Tax Credits as determined in Section 3.4 below,

C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section 3.2,

D is the Transmission Investment Base, as determined in Section 3.1.1 above, and

Federal Income Tax is the rate determined in Section 3.1.2.2 above.

3.2 <u>Transmission Depreciation and Amortization Expense</u> shall equal the sum of the Transmission Provider's:

- Depreciation Expense for Transmission Plant, plus
- An allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation expense by the Transmission Wages and Salaries Allocation Factor, plus
- An allocation of Amortization of Intangible Plant Expense calculated by multiplying Amortization of Intangible Plant Expense by the Transmission Wages and Salaries Allocation Factor.

3.3 <u>Transmission Related Amortization of Investment Tax Credits</u> shall equal the Transmission Provider's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

3.4 <u>Transmission Operation and Maintenance Expense</u> shall equal be as determined in accordance with Section 2.2.24.

3.5 <u>Transmission Related Administrative and General Expenses</u> shall equal the sum of the Transmission Provider's:

- Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor,
- Property Insurance multiplied by the Plant Allocation Factor, and
- Expenses included in Account 928 related to FERC Assessments multiplied by the Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments in Account 928 plus specific transmission related expenses included in Account 930.1

3.6 <u>Transmission Related Taxes Other Than Income Taxes</u> shall equal the sum of the Transmission Provider's:

- Balance of Property Taxes direct assigned to transmission, multiplied by the ratio of (a) Transmission Plant to (b) the sum of Transmission Plant and the gross balances associated with IPC Order 2003 Interconnection Facilities and the Transmission Provider's solely- and jointly-owned generator step-up facilities,

- An allocated amount of Property Taxes direct assigned to general plant calculated by multiplying Property Taxes direct assigned to general plant by the Transmission Wages and Salaries Allocation Factor,
- An allocated amount of Payroll Taxes calculated by multiplying Payroll Taxes by the Transmission Wages and Salaries Allocation factor, and
- An allocated amount of Other Fees and Charges calculated by multiplying Other Fees and Charges by the Plant Allocation Factor.

3.7 Amortization of RTO Development Costs shall equal $922,866 each year for the five-year period May 1, 2008 through April 30, 2013. Commencing May 1, 2013, Amortization of RTO Development Costs shall be $0.

4.0 Depreciation Rates For Use In Formula Rate

4.1

Account Number	Column A Depreciation Rates for determining depreciation expense through May 31, 2012	Column B Depreciation Rates for determining depreciation expense beginning June 1, 2012
350.20	1.51%	1.39%
350.21	1.50%	-
352.00	1.68%	1.84%
353.00	2.06	1.90%
354.00	1.96%	1.70%
355.00	2.81%	2.77%
356.00	1.92%	2.25
359.00	0.98%	0.79%
390.11	2.38%	2.58%
390.12	2.24%	1.90%
390.20	2.58%	2.15%
391.10	4.97%	2.88%
391.20	24.37%	11.12%
391.201	-	-
391.21	13.96%	11.22%
391.211	-	-
392.10	6.23%	7.50%
392.30	8.62%	1.73%
392.40	3.58%	7.36%
392.50	1.49%	3.53%
392.60	3.69%	4.14%
392.70	2.39%	3.21%
392.90	1.99%	2.10%
393.00	5.40%	3.30%
394.00	4.84%	4.13%
395.00	5.39%	4.29%
396.00	6.95%	1.66%
397.10	6.16%	4.25%
397.20	6.99%	5.38%
397.30	8.36%	5.31%
397.40	8.20%	7.90%
398.00	9.57%	5.20%

4.1.1 For service provided during the period October 1, 2012 through September 30, 2013 (for which the transmission revenue requirement is based on 2011 costs) the depreciation rates in column A will be used to determine depreciation expense. For service provided during the period October 1, 2013 through September 30, 2014 (for which the transmission revenue requirement is based on 2012 costs), the depreciation rates in column A will be used to determine depreciation expense for January 1, 2012 through May 31, 2012, and the depreciation rates in column B will be used to determine depreciation expense for June 1, 2012 through December 31, 2012. For service provided during the period October 1, 2014 through September 30, 2015 (for which the transmission revenue requirement is based on 2013 costs), the depreciation rates in column B will be used to determine depreciation expense.

4.2 In the event that the Idaho Public Utilities Commission (IPUC) issues a final order approving changes to the depreciation rates set forth in Section 4.1, Idaho Power will file such changed rates with the FERC pursuant to Section 205 of the Federal Power Act within 45 days of the issuance of such final order, to be made effective on the same date as such rates are made effective by the IPUC. If as a result of FERC's review or for any other reason, the depreciation rates approved by FERC for ratemaking purposes differ from those approved by the IPUC, the inputs to the formula rate will be calculated using the FERC-approved depreciation rates.

5.0 Network Upgrade Prepayments and Reimbursable Interest

Idaho Power shall record Network Upgrade Prepayments and Reimbursable Interest in Account 252. Such amounts shall be subtracted from Account 252 as reimbursed. Reimbursable interest earned by an Interconnection Customer (as defined in Attachment M of the Tariff) during the construction of a Network Upgrade (as defined in Attachment M of the Tariff) under a Large Generator Interconnection Agreement pursuant to Attachment M of the Tariff shall be capitalized in Account 107 as AFUDC.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-20

IDAHO POWER COMPANY

TATUM, DI
TESTIMONY

EXHIBIT NO. 5

IDAHO POWER COMPANY
Transmission Cost of Service Rate Development
12 Months Ended 12/31/2012

IDAHO POWER COMPANY
RATE CALCULATION

		Source		Amount
	TRANSMISSION RATE BASE			
1	Transmission Plant (excluding Asset Retirement Costs)	FF1 p207 58(g) less 57(g)	$	930,229,983
2	Generator Step Up Facilities	Schedule 7		(22,535,890)
3	LGI's	Schedule 8		(1,041,147)
4	Account 252-Transmission (Net)	Schedule 9		(1,332,405)
5	General Plant (excluding Asset Retirement Costs)	Schedule 1		38,319,569
6	Intangible Plant	Schedule 1		7,815,583
7	Transmission Plant Held For Future Use	FF1 p214 4d + 5d + 10d + 23d		1,132,474
8	General Plant Held For Future Use	Schedule 1		436,134
9	Transmission Depreciation Reserve (Acct 108) (excluding Asset Retirement Costs)	FF1 p 219 25(b) less 108.100 = 0		(285,425,520)
10	Transmission Depreciation Reserve Generator Step-Ups	Schedule 7		10,617,990
11	Transmission Depreciation Reserve LGI's	Schedule 8		161,813
12	General Plant Depreciation Reserve (excluding Asset Retirement Costs)	Schedule 1		(14,284,412)
13	Amortization of Utility Plant	Schedule 1		(2,979,941)
14	ADIT Allocated to Trans	Schedule 1		(63,360,246)
15	ADIT Allocated to Gen & Intang	Schedule 1		(3,224,093)
16	Transmission Related Prepayments	Schedule 1		1,647,569
17	Transmission Materials & Supplies	Schedule 1		13,712,116
18	Transmission Cash Working Capital	Schedule 1		4,970,027
19	Unamortized RTO Development Costs	OATT Attach H, 3.1.1.11(f)		-
20	Transmission Rate Base	Sum (1) Thru (19)		614,859,604
21				
22	**RETURN AND ASSOCIATED INCOME TAXES**			
23	Overall Return	Schedule 6		0.08113
24	Composite Income Tax (Federal and State)	Schedule 6		0.03496
25	Return and Income Taxes	(20)*((23)+(24))		71,379,051
26				
27				
28	**EXPENSES**			
29	Deprec Expense: Transmission	Schedule 2		17,663,011
30	Deprec Expense: General Plant	Schedule 2		1,349,157
31	Amortization Expense: Intangible Plant	Schedule 2		971,740
32	Amort of ITC (Acct 411.4)	Schedule 2		(634,572)
33	O&M Expense: Transmission	Schedule 2		28,521,540
34	Less Account 561 (Load Dispatching)	FF1 p 321 84b to 92b		(2,743,844)
35	Less: Account 565 (Transmission of Electricity By Others)	FF1 p 321 96b		(6,294,410)
36	O&M Expense: A&G	Schedule 2		20,276,930
37	Taxes Other than Income:	Schedule 2		5,560,569
38	Amortization of RTO Development Costs	OATT Attach H, 3.7		-
39	Interest Expense (Network Upgrade Prepayments)	Schedule 9		82,023
40	Transmission Expense	Sum (29) Thru (39)		64,752,143
41	Gross Transmission Revenue Requirement	(25) + (40))		136,131,195
42				
43	Transmission Revenue Credits	Schedule 4		(17,890,979)
44				
45	**Net PTP Transmission Revenue Requirement**		$	118,240,216
46				
47	**System Peak Demand - MW**	Schedule 5		5,186
48				
49	Annual Rate $/kW per year	(45)/((47)*1000)		22.80
50	Monthly Rate $/kW per month	(49) / 12		1.9000
51	Weekly Rate $/kW per week	(49) / 52		0.4385
52	Daily Rate $/kW per day (Mon-Sat)	(51) / 6		0.0731
53	Daily Rate $/kW per day (Sunday)	(51) / 7		0.0626
54	Hourly Rate $/MW per hour (Peak)	(49)*1000 / 4896		4.66
55	Hourly Rate $/MW per hour (Off-Peak)	(49)*1000 / 8760		2.60